



Research paper

Evaluating proppant performance and fracture conductivity dynamics in the Shenhu marine hydrate reservoir, South China Sea

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ABSTRACT

Hydraulic fracturing, which creates propped fractures to establish high-conductivity pathways near production wells, has emerged as a promising technology for boosting gas production efficiency in low-permeability marine natural gas hydrate (NGH) reservoirs. However, the effect of depressurization and hydrate decomposition on fracture conductivity remains unclear. This study examines the performance of proppants in propping artificial fractures and monitors changes in fracture conductivity and proppant embedment depth during depressurization and hydrate decomposition. Firstly, the changes in fracture conductivity during closure pressure loading and hydrate decomposition were measured by quantitatively injecting pre-cooled methane gas using an API-standard fracture conductivity chamber specifically designed for hydrates. It was found increasing closure pressure to 7.5 MPa led to a decrease in fracture conductivity that was more than 6.9 times greater than that caused by slow hydrate decomposition. The main causes of this conductivity damage were proppant embedment and rearrangement, with rearrangement being the more significant factor. Notably, proppant embedment was more pronounced in hydrate reservoirs compared to other unconventional reservoirs. After the complete decomposition of hydrates, the embedment depth was measured using White Light Optical Profilometry, showing that at a low closure pressure of 7.5 MPa, the embedment depth reached up to 28 % of the proppant diameter. Fractures using 40/70 mesh proppants exhibited higher conductivity compared to those using 30/50 mesh proppants. Additionally, increasing proppant concentration increased fracture conductivity, primarily due to reduced embedment and increased fracture width. Different proppant concentrations displayed distinct mechanisms of conductivity damage: single-layer proppants saw a rapid conductivity decline due to proppant embedment, while multilayer proppants experienced significant reductions from proppant compaction. Seawater flow on the fracture surface further decreased conductivity by 20.68 %, mainly due to the softening and expansion of clay, which exacerbated proppant embedment. This study emphasizes the importance of closure pressure and proppant properties in maintaining fracture network permeability for long-term gas extraction in clayey-silt NGH reservoirs, providing key insights for optimizing marine NGH production.

1. Introduction

Natural gas hydrate (NGH), known for its high energy density, abundant reserves, and clean combustion properties, has garnered significant global attention (Figueres et al., 2017). NGH is a clathrate crystalline compound formed from natural gas and water under conditions of low temperature and high pressure. It is primarily found in permafrost regions and deep-sea sediments along continental margins (Sloan, 2003). Several countries, including the United States, China, India, and Japan, have made substantial investments in NGH exploration and production (Flemings et al., 2020; Kumar et al., 2019; Wang

et al., 2022; Yamamoto, 2018). In the second offshore production trial conducted in the clayey-silt NGH reservoir of the South China Sea, a total gas output of $86.14 \times 10^4 \text{ m}^3$ was realized over a continuous 30-day period, demonstrating the feasibility of safe and efficient NGH extraction in such reservoirs (Ye et al., 2020). However, there remains a significant gap between this field test's production rate and the levels needed for commercial viability. Addressing challenges such as low production rates, inadequate conductivity around the production wells, and short periods of stable production is crucial to achieving commercial-scale NGH extraction. These challenges are mainly attributed to the low permeability (2–5 mD in the trial area) of the NGH

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reservoir (Su et al., 2017).

To improve gas production efficiency in low permeability NGH reservoirs, utilizing reservoir stimulation methods is crucial (Konno et al., 2016). Hydraulic fracturing stands out as an effective approach to enhance oil and gas yields. Widely applied in tight oil and gas fields, this technique generates fractures within the reservoir, thereby establishing high-conductivity pathways around production wells. To date, the fracturability of hydrate-bearing sediments has been assessed through experimental studies. Ito et al. (2008) conducted experiments to comprehend the hydraulic fracturing behavior in sand and mud layers, observing fracture-like structures at the sand-mud interface post-fluid injection. Konno et al. (2016) conducted hydraulic fracturing tests using distilled water on methane hydrate-bearing sandy samples in a triaxial pressure cell, finding permeability increased after fracturing and remained high even after re-confining and closing the fractures. Too et al. (2018) carried out experiments on high saturation hydrate-bearing sand specimens, showing that sand specimens with 50–75 % hydrate saturation could be fractured into penny-shaped cracks. Sun et al. (2021b) assessed hydraulic fracturing's feasibility in hydrate-bearing clayey-silt sediments, using X-ray computed tomography to reveal the internal fractured structure of the specimens, identifying an initial tensile failure followed by an erosion stage. Ma et al. (2022) explored how sediment properties and fracturing fluid parameters affect fracture initiation, propagation, and morphology in frozen and methane hydrate-bearing clayey-silt sediments, confirming the fracturability of these sediments even at low hydrate saturations. Liu et al. (2020) developed a model to evaluate hydraulic fracturing feasibility in hydrate-bearing sediments, integrating experimental data with the analytic hierarchy process-entropy method. These studies collectively suggest that hydrate-bearing clayey-silt sediments are amenable to hydraulic fracturing.

Fracture conductivity, a key parameter after hydraulic fracturing, is determined by the product of fracture width and permeability (Osipov, 2017). It serves as a measure of a fractured porous medium's ability to facilitate the flow of formation fluids, such as gas and water, through the fracture in the reservoir (Li et al., 2022). Maintaining adequate conductivity in an artificial fracture network is a critical challenge for achieving commercial exploitation, particularly in soft and clay-rich formations (Akbari et al., 2017; Liu et al., 2023). Current researches on fracture conductivity in shale reservoirs have focused extensively on laboratory testing, proppant embedment, and modeling of proppant embedment (Katende et al., 2021). Fracture conductivity is mainly influenced by factors such as the proppant pack layer, fracture surface roughness, mineralogy, fluids, temperature, and closure stress (Katende et al., 2023a). Enhanced fracture conductivity is linked to proppant size, increased porosity of the proppant pack, while reduced fracture conductivity is influenced by factors such as fracture closure stress (Katende et al., 2022). For a monolayer of proppant, studies have shown that proppant embedment can reduce conductivity by up to 50 % (Katende et al., 2023b). Overall, proppant performance in different reservoirs primarily depends on the mechanical interactions between the proppant and fracture surfaces.

Despite extensive research on factors influencing fracture conductivity in shale gas reservoirs and coalbed methane (CBM) reservoirs, including proppant sizes, concentration, type, distribution modes, closure pressure, and proppant embedment (Bandara et al., 2019, 2021b; Embedment, 2014), there is a notable lack of studies specifically addressing the conductivity of artificial fractures in clayey-silt NGH reservoirs. Comparing with other unconventional gas reservoirs, clayey-silt NGH reservoirs exhibit distinctive geological and mechanical properties (Waite et al., 2009). These include weak cementation, a small elastic modulus, and a large Poisson's ratio, which contribute to proppant embedment within fractures. Moreover, the mechanical strength tends to decrease with hydrate decomposition, potentially leading to a more pronounced decline in fracture conductivity. Furthermore, differences in burial depth and exploitation technology between NGH and

shale gas reservoirs introduce additional variations in fracture conductivity characteristics. Understanding these differences is crucial for addressing the unique challenges posed by clayey-silt NGH reservoirs in maintaining sustained fracture conductivity.

However, there is very limited research on the fracture conductivity of NGH reservoirs (Li et al., 2024). Qu et al. (2022) developed solidified phase change proppants aimed at enhancing gas production in NGH reservoirs. They evaluated the fracture conductivity of both solidified phase change proppants and quartz sand proppants across a range of particle sizes under closure pressures ranging from 0 to 20 MPa. Their findings revealed that the solidified phase change proppant outperformed the quartz sand proppant in maintaining fracture conductivity, especially at a closure pressure of 20 MPa for particle sizes exceeding 3 mm. However, it was noted that gas hydrates were absent in the sediment samples, and the proppant concentration was relatively high, fixed at 10 kg/m². Li et al. (2023) conducted experiments to investigate the impact of proppant size, concentration, hydrate saturation, and closure pressure on fracture conductivity within hydrate-bearing sediments. They developed a comprehensive model to describe how these four factors together influence fracture conductivity in such sediments. These studies contribute significantly to the understanding of fracture conductivity in NGH reservoirs. However, the studies did not address the gas production process and its parameters, highlighting the need for further investigation into fracture conductivity in clayey-silt NGH reservoirs.

This research focuses on the properties of the South China Sea's clayey-silt NGH reservoir and seeks to explore the effectiveness of artificial fracture propping while also tracking changes in fracture conductivity and embedment depth during the processes of depressurization and hydrate decomposition. Utilizing a custom-designed conductivity cell that adheres to API standards, the study examines how fracture conductivity varies in response to different proppant sizes, concentrations, and the wettability of the fracture-contact interface. Ultimately, the aim is to enhance our understanding of effective artificial fracture propping in NGH clayey-silt reservoirs, thereby ensuring the long-term permeability of the fracture network for sustained gas production.

2. Experimental parameters and procedures

Proppant size and concentration are recognized as critical factors influencing fracture conductivity. In this study, three proppant sizes (30/50, 40/70, 70/140 mesh) were selected for initial experiments. Based on the results from these initial tests, subsequent experiments were conducted to explore the impact of varying proppant concentrations and fracture-contact wettability, using the optimal proppant size identified in the earlier phase. The proppant concentrations tested included multilayer, uniform monolayer, and partial monolayer arrangements (Bandara et al., 2021a). The details of the experiments are provided in Table 1.

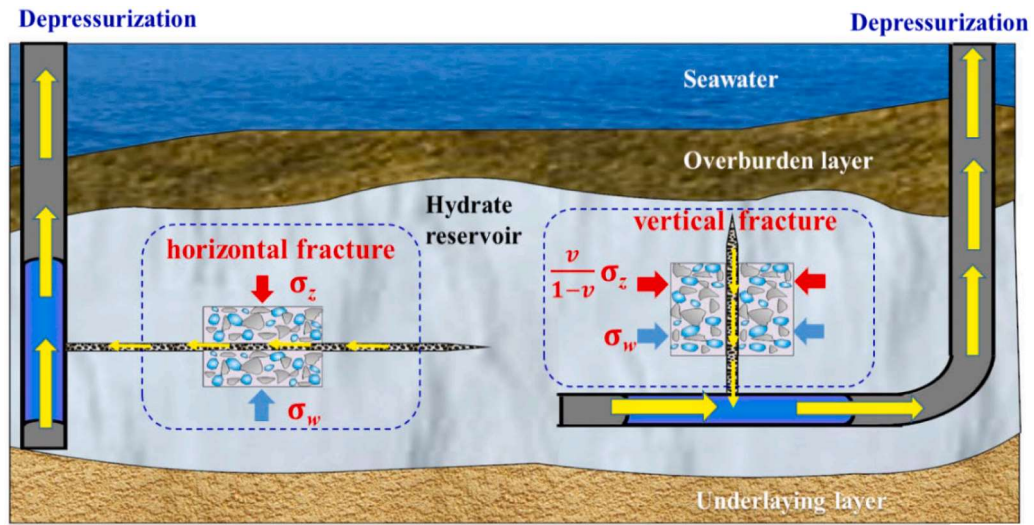
2.1. Selection of closure pressure

Closure pressure is a predominant factor influencing artificially proppant-filled fractures, which can be affected by pore pressure, overburden pressure, and depressurization range, as illustrated in Fig. 1. The formulations for closure pressure in horizontal and vertical fractures are given by Eq. (1) and Eq. (2), respectively. Considering the characteristic of NGH reservoir in the South China Sea, where the water depth typically exceeds 1200 m and the hydrate-bearing reservoir is situated approximately 200 m below the seafloor, the pore pressure within the hydrate-bearing reservoir is approximately 15 MPa (Ye et al., 2020). The overburden pressure in the NGH reservoir is related to the thickness of the overburden layer. The overburden pressure in the NGH reservoir is contingent upon the thickness of the overburden layer. In the South China Sea, the overburden thickness of the hydrate reservoir (buried

Table 1

Experimental parameters of fracture conductivity measurement.

Runs	Hydrate saturation/ %	Proppant mesh	Proppant mass/ g	Proppant concentration/ kg·m ⁻²	Height of proppant pack/ mm	Proppant distribution	Fracture Contact
1-1	32.25	40-70	16.13	2.5	1.5	multilayer	gas
1-2	42.92	40-70	16.13	2.5	1.5	multilayer	gas
1-3	44.82	40-70	16.13	2.5	1.5	multilayer	gas
2	36.91	70-140	16.13	2.5	1.7	multilayer	gas
3	35.12	30-50	16.13	2.5	1.4	multilayer	gas
4	36.01	40-70	32.26	5	3	multilayer	gas
5	35.32	40-70	48.39	7.5	4.5	multilayer	gas
6	30.12	40-70	48.39	7.5	4.5	multilayer	water-wet
7	33.49	40-70	8.07	1.25	0.75	multilayer	gas
8	32.45	40-70	4.52	0.7	0.4	uniform monolayer	gas
9	32.51	40-70	1.94	0.3	0.4	partial monolayer	gas

**Fig. 1.** Schematic diagram of the closure pressures for horizontal and vertical fractures in NGH reservoirs.

depth) ranges from approximately 100 to 300 m (Li et al., 2019), resulting in corresponding overburden pressures of about 0.8 to 2.4 MPa, as calculated by Eq. (3). Additionally, based on the depressurization trial production in the South China Sea, the depressurization range (σ_w) in our experiments is estimated to range between 1 and 4 MPa (Qin et al., 2020).

$$\sigma_{cv} = \frac{\nu}{1-\nu} \sigma_z + \sigma_w \quad (1)$$

$$\sigma_{ch} = \sigma_z + \sigma_w \quad (2)$$

$$\sigma_z = P_z - P_0 = (\rho_s - \rho_w)gh_s \quad (3)$$

$$\sigma_w = P_0 - P \quad (4)$$

where σ_{cv} is the closure pressure of vertical fracture, MPa; ν is poisson's ratio of hydrate-bearing sediments, 0.15–0.5 (Li et al., 2021); σ_z is in-situ stress, MPa; σ_w is depressurization range, MPa; σ_{ch} is closure pressure of horizontal fracture, MPa; ρ_s is the equivalent density of overburden sediments, kg/m³; ρ_w is the water density, kg/m³; h_s is buried depth of NGH reservoir, m; P_0 is the initial reservoir pore pressure, MPa; P is the reservoir pore pressure during production, MPa.

Therefore, the closure pressures for horizontal and vertical fractures in the gas hydrate trial production area of the South China Sea are approximately 1.8–6.4 MPa and 1.14–6.4 MPa, respectively. Based on these values, this study selected a closure pressure range of 1–7.5 MPa.

2.2. Experimental materials

The experimental materials employed in this study encompass clayey-silt sediments, proppant, deionized water, and methane gas. The clayey-silt sediments were meticulously prepared, matching the grain size distribution found in sediments from the Shenhu area of the South China Sea. A comparison of the grain size distribution curves of the prepared sediments and those found in nature (Kuang et al., 2019; Wu et al., 2022) is shown in Fig. 2. An analysis of the prepared clayey-silt sediments using a laser particle size analyzer revealed a D50 value of 8.23 μ m, closely matching the D50 value of approximately 8 μ m found in the depth range of 135–180 m below seafloor (mbsf) from the LW3-H4-BH1 well (Kuang et al., 2019), indicating similar particle size distribution characteristics. The weight ratio of quartz sand (1250 mesh), carbonates (1000 mesh), illite (1000 mesh), and montmorillonite (1000 mesh) in the clayey-silt sediments used for these experiments is 0.54:0.16:0.20:0.10. Three types of ceramic proppants, namely 30/50, 40/70, and 70/140 mesh, were employed in this study, each with respective volume densities of 1.83 g/cm³, 1.67 g/cm³, and 1.46 g/cm³. Analytical grade methane (99.999 %, supplied by Beifang Special Gas Industry Corporation) and deionized water were used throughout the experiments.

2.3. Experimental apparatus

The fracture conductivity test with a proppant pack in hydrate-bearing clayey-silt sediments was conducted using a self-designed fracture conductivity evaluation system specifically for hydrate reservoirs.

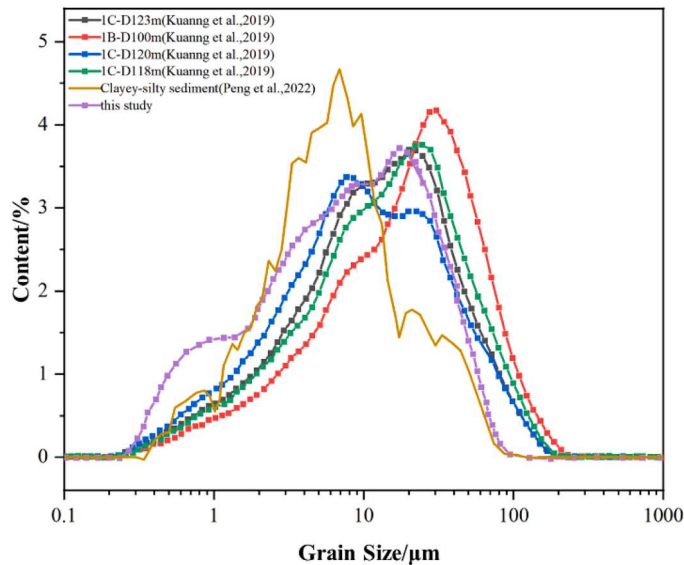


Fig. 2. Particle size distribution curves for the prepared and natural sediments.

This system can measure fracture conductivity under varying hydrate saturations, closure pressures, and temperatures. The main components of the system include a gas injection unit, a pressure-loading system, a low-temperature fracture conductivity chamber (API standard), a low-temperature circulation system, a monitoring and control unit, and a back pressure unit. Fig. 3 depicts both the schematic diagram and photograph of the fracture conductivity evaluation system. The proppant particles are placed between two sediment samples within the fracture conductivity chamber, which can apply a closure pressure up to 35 MPa and accommodate sediment samples with fractures up to 12 cm in height. The proppant pack thickness ranges from 0 to 1.27 cm, while the thickness of hydrate-bearing sediments varies from 0 to 5 cm. The low-temperature water bath controls temperatures from -15 to 30 °C with an accuracy of ± 0.1 °C. The apparatus is equipped with a high-pressure constant-flow pump to ensure constant water flow into the fracture conductivity chamber, with the pump operating at a maximum pressure of 70 MPa and a flow range of 0.001 to 60 mL/min. A thermocouple (-50 – 150 °C, ± 0.01 °C), two pressure sensors (0–25 MPa, ± 0.3 %) and one pressure difference sensor (0–40 kPa, ± 0.1 %) are connected to the conductivity chamber to measure temperature and pressure. A displacement sensor with a range of 0 to 100 mm and precision of ± 0.01 mm is also included. Two gas mass flow controllers, with maximum flows of 5 L/min and 20 L/min, are used to inject precooled methane gas at a constant flow rate for conductivity measurement.

2.4. Experimental procedures

In the gas production process from NGH reservoirs, two primary factors contribute to the potential damage to fracture conductivity in hydrate-bearing clayey-silt sediments: (a) Increased closure pressure due to depressurization: The rise in closure pressure during depressurization tends to close the fracture, ultimately leading to a decrease in fracture conductivity. (b) Hydrate decomposition near the propped fracture: Hydrate decomposition near the propped fracture weakens the mechanical properties of the sediment, exacerbating proppant embedment and intensifying fracture closure. To comprehensively evaluate the impact of these distinct factors on fracture closure, the experiments adopt a two-step testing method. This method includes both the closure pressure loading process and the hydrate decomposition process. The sequential steps of the detailed experimental procedure are as follows:

(1) Preparation of Clayey-Silty Sediments:

- i) Dried sediments with a total mass of 225.46 g were prepared and mixed evenly with 27.09 g deionized water, achieving an initial water saturation of 60 %.
- ii) Subsequently, the samples were shaped using specially designed stainless-steel molds, with predetermined thickness and porosity parameters set at 2 cm and 35 %, respectively. The chosen porosity closely mirrors the actual porosity observed in the Shenhu area of the South China Sea (Li et al., 2019).
- iii) Finally, the lower sediment sample, proppants and the upper sediment sample were sequentially installed in the conductivity chamber. To ensure uniform placement, a scraper was used to level the proppants and measure their thickness. By initially placing the propped fractures in a dry state, we prevented the presence of water in the fractures, thus avoiding hydrate formation within them.

(2) Hydrate Formation:

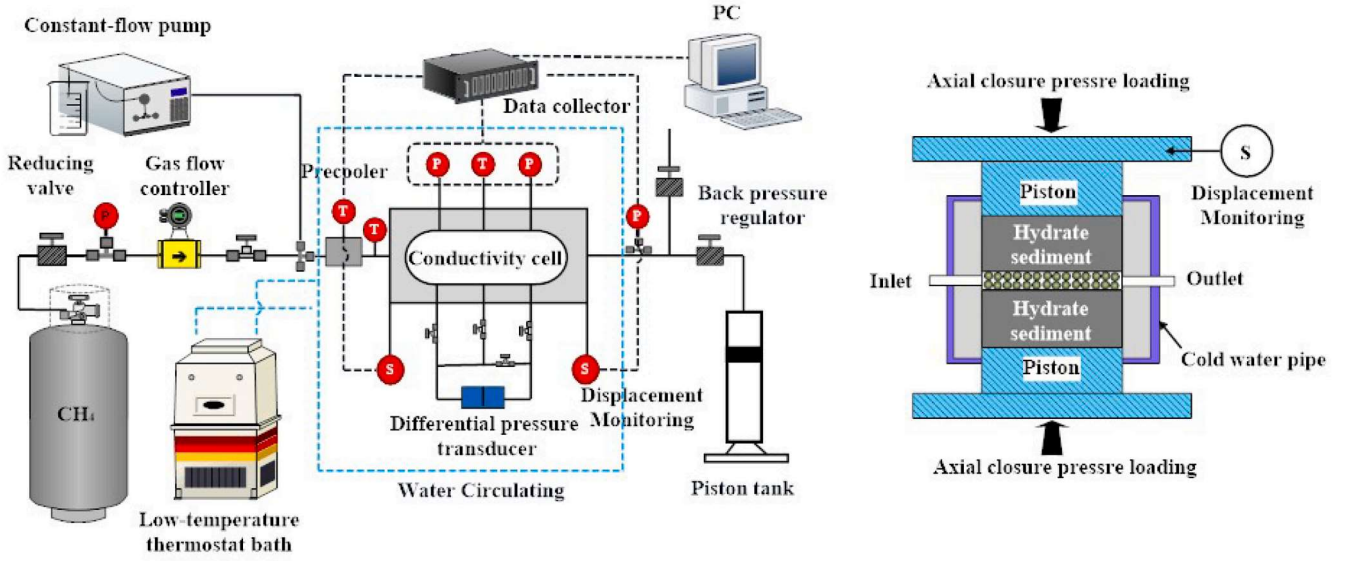
- i) The gas pipeline was connected, and the sealing of the conductivity chamber was checked.
- ii) The gas pressure within the conductivity cell was pressurized using methane gas to the desired level (8.5–9.0 MPa). Once stabilized for 2 h without fluctuations, the water bath temperature was adjusted to 273.25 K to cool the conductivity cell. By controlling the pressure of the injected methane gas, sediment samples with different hydrate saturations were synthesized.
- iii) Following 12 h of sustained temperature and pressure conditions, it was assumed that hydrate formation had reached completion. A critical consideration was made to guarantee that the axial pressure exceeded the pore pressure by approximately 0.5 MPa.

(3) Loading Closure Pressure and Measuring Conductivity:

- i) To prevent hydrate decomposition during the closure pressure loading, the back pressure regulator was adjusted to 4.5 MPa.
- ii) Subsequently, different effective closure pressures were incrementally increased in a stepwise manner (1.0, 2.0, 4.0, 6.5 MPa) to investigate the sensitivity of effective closure pressure to fracture conductivity. The process involved monitoring the displacement decline curve, and when it stabilized, the fracture conductivity with methane was measured for each effective closure pressure.
- iii) Finally, the back pressure was adjusted to 3.5 MPa (slightly above the hydrate phase equilibrium pressure at this temperature) from 4.5 MPa, achieving an effective closure pressure of 7.5 MPa, with the loaded axial pressure remaining constant at 11 MPa. The fracture conductivity was measured for the last time before hydrate decomposition.

(4) Hydrate Decomposition and Measuring Conductivity:

- i) The procedure involves three sequential stages: quick gas release, slow hydrate decomposition, and measuring fracture conductivity.
- ii) The first phase involves a swift gas discharge by opening the valve leading to the vacuum piston tank (which has a usable volume of 40 ml), resulting in a quick decline in gas pressure inside the conductivity cell. The valve was closed once the pressure stabilized and had decreased by approximately 0.5 MPa.
- iii) Following this, as the hydrate began to decompose, there was a gradual increase in pressure within the conductivity cell, moving towards the equilibrium pressure of the hydrate phase.
- iv) The final step entailed measuring the fracture conductivity using methane gas, with the entire procedure being repeated until the methane hydrate had fully decomposed.



(a) Schematic diagram



(b) Photograph

Fig. 3. Fracture conductivity evaluation system for hydrate reservoir.

(5) Water Flowing:

In experiment 6, the proppant was laid at a concentration of 7.5 kg/m^2 , followed by execution of steps (1) through (4). Subsequently, 1200 mL of seawater was pumped into the conductivity cell at a rate of 10 mL/min using a constant flow pump. Upon completing the water injection, the fracture conductivity was measured using methane gas.

2.5. Date processing

The date processing included the calculations of hydrate saturation

S_h , closure pressure σ_c and fracture conductivity KW_f . The hydrate saturation was defined as the ratio of the hydrate volume and the total pore volume, and it could be calculated with Eq. (5) and (6).

$$S_h = \frac{(n_{g, \text{initial}}^{CH_4} - n_{g, \text{end}}^{CH_4}) \times (M_h + 6 \times M_{H_2O})}{\rho_h \times V_{\text{pore}}} \quad (5)$$

where V_{pore} denotes the total pore volume; $n_{g, \text{initial}}^{CH_4}$ and $n_{g, \text{end}}^{CH_4}$ express the number of methane moles in the cell before and after hydrate formation, respectively; M_h and M_{H_2O} denote the molecular weight of the methane

and water, 16 g/mol and 18 g/mol, respectively; ρ_h represents the density of the methane hydrates, 0.91 g/cm³.

The number of moles of methane in the gas phase was evaluated as follows:

$$n_g^{CH_4} = \frac{PV}{zRT} \quad (6)$$

where z denotes the compressibility factor calculated by the Benedict–Webb–Rubin–Starling equation of state (Starling and Han, 1972).

The closure pressure σ_c is calculated with Eq. (7).

$$\sigma_c = \sigma - \sigma_{pore} \quad (7)$$

where σ is axial loading stress, σ_{pore} is the pore pressure in the cell.

The fracture conductivity of proppant pack (KW_f) is defined as the product of the width of the fracture and its permeability, and the calculation formula at Darcy flow conditions is shown by Eq. (8).

$$KW_f = \frac{2P_0Q_0\mu L}{W(P_1^2 - P_1 - \Delta P^2)} \quad (8)$$

where KW_f is the propped fracture conductivity, D-cm; P_0 is atmospheric pressure, 0.1 MPa; For a standard API cell, L is the sample length, 12.7 cm; W is the width of the conductivity cell, 3.81 cm; μ is the gas viscosity at the experimental temperature, mPa-s; Q_0 is the flow rate under atmospheric pressure, cm³/s; P_1 is the inlet pressure of the conductivity cell, MPa; ΔP is the pressure difference, MPa.

3. Results and discussion

3.1. Variation of fracture conductivity and pistons displacement during loading closure pressure and hydrate decomposition

Fracture conductivity and piston displacement exhibited similar patterns of change across different experiments. Therefore, Run 1, which used 2.5 kg/m² of 40/70 mesh proppants, was selected to demonstrate

the changes in temperature, pressure, hydrate saturation, piston displacement, and fracture conductivity during the stages of closure pressure loading and hydrate decomposition.

Fig. 4 illustrates the evolution of cell pressure and temperature for Run 1. The process is divided into three stages based on changes in hydrate saturation: the loading closure pressure stage (S₁), the hydrate decomposition stage (S₂), and the post-decomposition stage (S₃). During S₁, the cell temperature remained relatively stable while slight pressure increases were observed, primarily due to gas-conductivity tests conducted during the first to fourth closure pressure loading processes. To prepare for quantitative hydrate decomposition, the cell pressure was reduced from 4.45 MPa to 3.45 MPa during the fifth loading, slightly exceeding the phase equilibrium pressure at 1.62 °C. In S₂, after a depressurization of 0.5 MPa, hydrate decomposition began, leading to a subsequent increase in cell pressure until it matched the phase equilibrium pressure. As depicted in Fig. 4, the temperature dropped by 0.1–0.2 °C due to the endothermic nature of hydrate decomposition, then increased and stabilized due to the cooling effect of the water bath. The minor decrease in phase equilibrium pressure after the second to fourth stages of hydrate decomposition may be attributed to the influence of clayey-silt sediment on the hydrate phase equilibrium (Sun et al., 2021a). In S₃, after the fifth depressurization of 0.5 MPa, the pressure only increased to 2.73 MPa, significantly lower than the phase equilibrium pressure, indicating the complete decomposition of hydrates.

Fig. 5 illustrates the variation of fracture conductivity and displacement during the processes of closing stress loading and hydrate decomposition. The results show that conductivity slightly decreased as hydrate saturation diminished. Specifically, after 5 rounds of depressurization, hydrate saturation dropped from 32.25 % to 0 %, and conductivity decreased from 5.20 D-cm to 3.76 D-cm. Over the course of the experiment, the overall fracture conductivity decreased by 11.38 D-cm. Of this reduction, 12.65 % was attributed to hydrate decomposition, while 87.35 % was attributed to the increase in closure pressure. Under constant closure pressure, conductivity decreased due to hydrate decomposition, though the reduction was less significant compared to

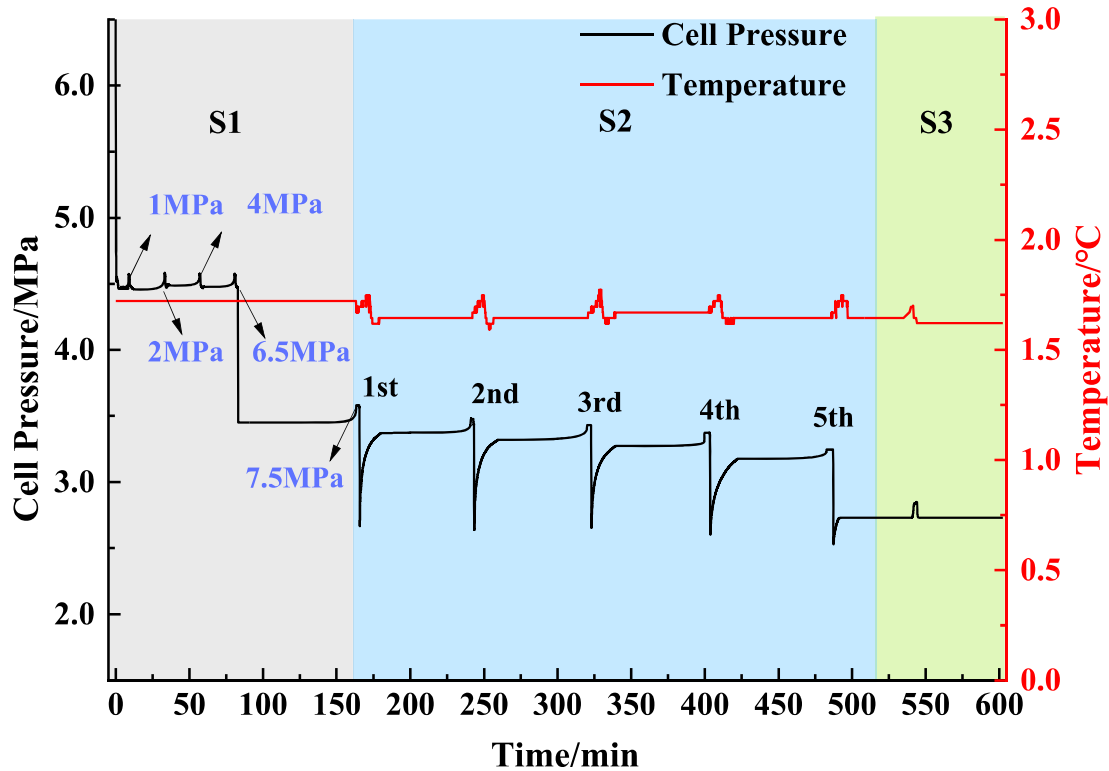


Fig. 4. Evolution of pressure and temperature in conductivity chamber.

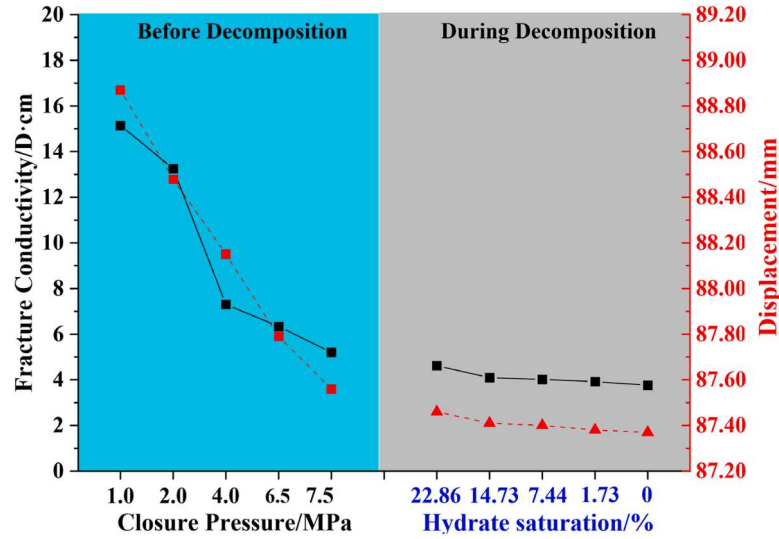


Fig. 5. Variation of fracture conductivity and displacement during closure pressure loading and hydrate decomposition.

the closure pressure loading process. Notably, conductivity remained relatively stable when the closure pressure was unchanged, consistent with findings from previous conductivity studies (Ahamed et al., 2019; Lacy et al., 1998). Given the unique mechanical properties of NGH reservoirs, many experiments have shown that hydrate saturation affects the elastic modulus of hydrate-bearing sediments. Specifically, a decrease in hydrate saturation leads to a reduction in the elastic modulus of the sediments (Sloan, 2003; Waite et al., 2009). We hypothesize that this decrease in the elastic modulus may contribute to further proppant embedding in both upper and lower hydrate-bearing sediments during the experiments. This proppant embedding likely causes a reduction in fracture width and porosity in the proppant pack, which in turn leads to a decrease in fracture conductivity.

As closure pressure increased and hydrate decomposition occurred, fracture conductivity gradually decreased, with displacement monitoring reflecting the ongoing fracture closure process. This study used 2.5 kg/m² of 40/70 mesh proppants to analyze variations in displacement and fracture conductivity. Additionally, the study explored the damage patterns and factors affecting fracture conductivity.

The displacement difference was calculated as the difference be-

tween the initial value and the detected displacement value, with the displacement value at 1 MPa closure pressure defined as the initial value for consistency. Building upon previous research results, the total displacement (T) in the experiment is composed of four primary components: average deformation of hydrate-bearing sediments ($H1-H2$) (Luo et al., 2020a), average proppant embedment depth (h), average proppant pack deformation ($D1-D2$), and average proppant deformation ($P1-P2$), where N_L is the number of proppant layers (Fig. 6). Eq. (9) was employed for the displacement analysis.

$$T = 2(H1 - H2) + (D1 - D2) + 2h + N_L(P1 - P2) \quad (9)$$

The proppants used in the experiment had an elastic modulus of 80 GPa and a single-particle crush strength of 141 MPa. Based on these properties, the closure pressure used in our study should not cause significant deformation or crushing of the proppants. Physical observations during the experiment, as shown in Fig. 7, confirmed that no proppant crushing occurred. Therefore, we simplified Eq. (9) to Eq. (10), excluding the effects of proppant deformation.

$$T = 2(H1 - H2) + (D1 - D2) + 2h \quad (10)$$

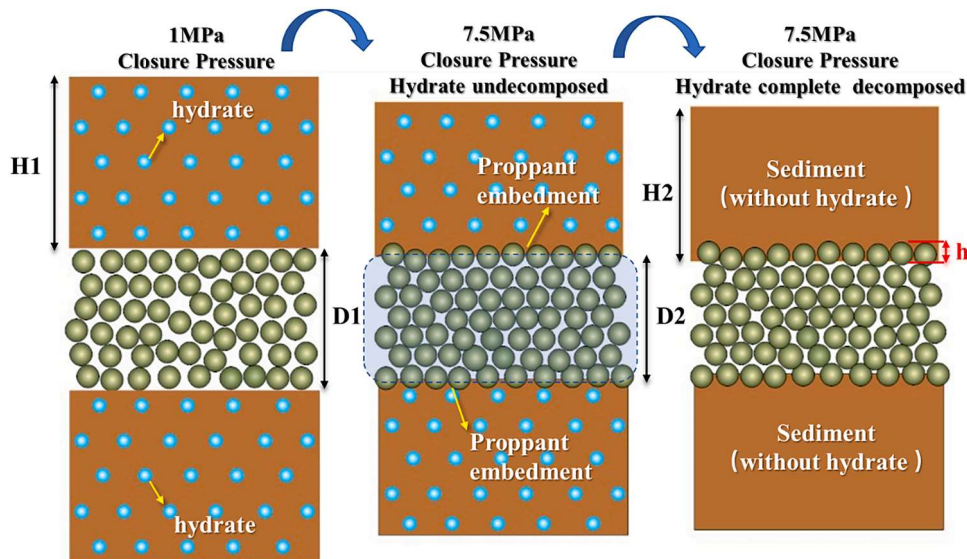


Fig. 6. Schematic of displacement change mechanisms: proppant packing rearrangement, hydrate-sediment deformation and proppant embedment.

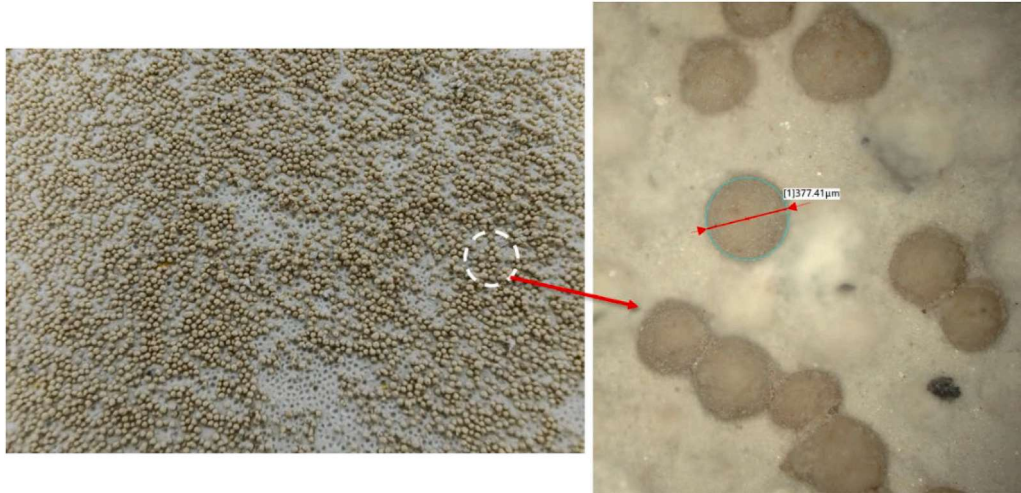


Fig. 7. Photos of proppant embedded in sediment after the experiment.

The results presented in Fig. 8 indicate that the displacement exhibited a rapid response to the increase in closure pressure. As the closure pressure rose from 1 to 7.5 MPa, the displacement decreased from 88.87 to 87.56 mm and further decreased to 87.36 mm after the complete hydrate decomposition. The percentage of displacement decline during the loading closure pressure stage was 87.33 %, which is closely aligned with the 87.35 % decrease in fracture conductivity observed, as depicted in Fig. 5. A similar trend was evident between displacement and fracture conductivity; specifically, each 1 MPa increase in closure pressure resulted in an average conductivity decrease of 1.32 D-cm.

Based on the above results, two key points can be inferred. Firstly, the primary reduction in piston displacement and conductivity occurred during the process of loading closure pressure, accounting for 87.33 % and 87.35 %, respectively. Secondly, after complete hydrate decomposition, fracture conductivity stabilized at 3.76 D-cm, showing only a modest decrease. Notably, the fracture conductivity did not sharply decrease with the decomposition of hydrates. This relatively stable conductivity can be attributed to the limited impact of hydrate

decomposition (hydrate saturation = 30–40 %) on the elastic modulus when the initial water saturation was around 60 %.

Overall, the observed trend before hydrate decomposition can be attributed to the increase in closure pressure, which led to a reduction in fracture width and greater proppant embedment. At the same time, this pressure increase caused changes in the proppant structure, resulting in reduced internal porosity and permeability. Consequently, the conductivity, which is the product of fracture width and permeability, decreased as closure pressure increased. During hydrate decomposition, the reduction in the elastic modulus of the sediments caused slight proppant embedment, further reducing fracture width and fracture conductivity.

For the case with 2.5 kg/m^2 of 40/70 mesh proppants, as illustrated in Fig. 5, fracture conductivity decreased both before and after hydrate decomposition. The rate of decrease in fracture conductivity slowed as hydrate decomposition progressed. Specifically, before decomposition, conductivity reduced by up to 65.65 % as closure pressure increased from 1 MPa to 7.5 MPa, and by up to 51.78 % at 4 MPa. This trend is consistent with observations in other unconventional gas reservoirs,

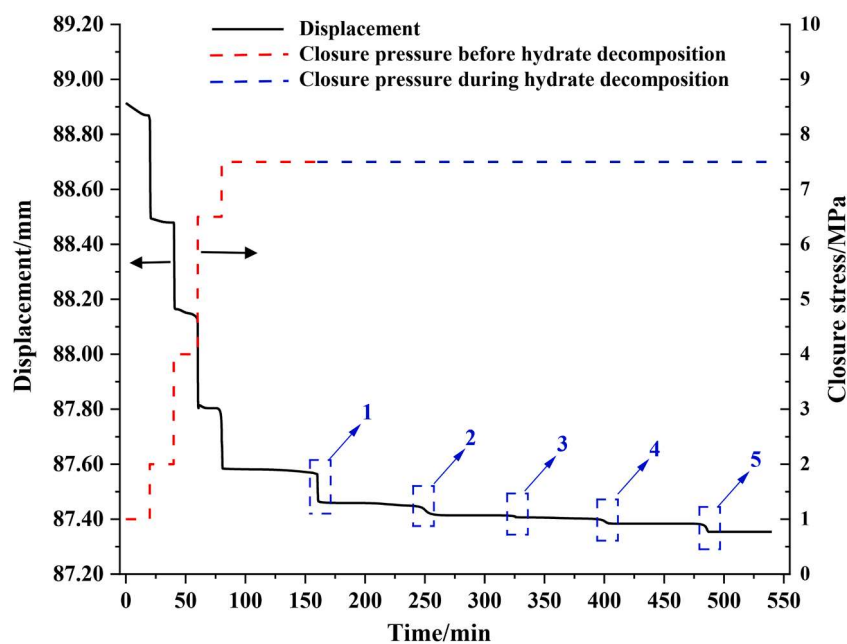


Fig. 8. Variation of piston displacement during closure pressure loading and hydrate decomposition.

which share a common characteristic: the decline rate of conductivity slows down as closure pressure increases. However, the closure pressure range in diagenetic reservoirs is significantly larger compared to marine hydrate reservoirs, indicating that marine hydrate reservoirs exhibit higher closure-pressure sensitivity in terms of fracture conductivity. Therefore, in the case of hydraulic fracturing in hydrate reservoirs, it is advisable to use a low depressurization range during extraction to ensure that the fracture conductivity is maintained under lower closure pressures.

To ensure the overall reliability and reproducibility of the experimental data, for a proppant concentration of 2.5 kg/m^2 , three experiments (S_h : 42.92 %, 44.82 %, 32.25 %) were conducted under identical processes and parameters to analyze the mean value and standard deviation of fracture conductivity. Since hydrate saturation was variable during the decomposition process, only the results of complete decomposition were considered. The standard deviations of conductivity (as shown in Fig. 9) were 1.09, 2.58, 0.65, 0.96, and 0.43, with the exception of the value 2.58 (closure pressure 2.0 MPa), which was notably higher. The other standard deviations indicate minimal variability. Given that conductivity is influenced by two distinct variables—permeability and fracture width—that inherently vary, the results reflect a high degree of reliability and consistency.

3.2. The effects of proppant meshes and concentrations on fracture conductivity

Fig. 10 illustrates the fracture conductivity of 30/50, 40/70, and 70/140 mesh ceramic proppants at a proppant concentration of 2.5 kg/m^2 . The dotted lines illustrate a downward trend in propped fracture conductivity across different closure pressures and hydrate saturations during hydrate decomposition. The results reveal that the 40/70 mesh demonstrated higher conductivity compared to the 30/50 and 70/140 mesh. During the closure pressure loading stage the conductivity of 40/70 mesh at 4 MPa was 16.13 % and 52.44 % higher compared to 30/50 and 70/140 mesh, respectively. During hydrate decomposition, the conductivity decreased as follows: from 2.78 to 2.14 D-cm for 30/50 mesh, from 4.62 to 3.76 D-cm for 40/70 mesh, and from 1.55 to 1.25

D-cm for 70/140 mesh. Additionally, a consistent pattern was observed across all three experiments: closure pressure had a more significant impact on conductivity reduction compared to hydrate decomposition. As closure pressure increased from 1 to 7.5 MPa, the contribution percentage of increased closure pressure to the total conductivity damage degree was 94.26 % for 30/50 mesh, 87.35 % for 40/70 mesh, and 96.63 % for 70/140 mesh.

Proppant embedment is a key factor contributing to fracture conductivity damage, as the depth of embedment directly affects fracture width, while the area of embedment influences the porosity of the proppant pack, thereby impacting permeability. As both fracture width and permeability decrease, fracture conductivity is reduced. Therefore, the proppant embedment depth was measured using White Light Optical Profilometry. Fig. 11 displays the embedment depth of different mesh sizes. Four random points on the surface of the sediments extracted from the conductivity cell after the experiment were determined. The results were $150.52 \text{ }\mu\text{m}$ for 30/50 mesh, $107.46 \text{ }\mu\text{m}$ for 40/70 mesh, and $58.02 \text{ }\mu\text{m}$ for 70/140 mesh. The ratio of embedment depth to proppant diameter was 32.53 % for 30/50 mesh, 28.50 % for 40/70 mesh, and 26.38 % for 70/140 mesh. As the proppant diameter decreased, the embedment depth also decreased. This phenomenon occurs because the smaller proppant diameter results in a larger contact area with the sediment surface, which, under the same closure pressure, reduces the force exerted on individual proppants, thereby decreasing the embedment depth.

Building upon the depth data regarding proppant embedment, an intriguing phenomenon emerged: the observed pattern of fracture conductivity in clayey silt sediments differed from that in other unconventional energy reservoirs. In this study, 40/70 mesh exhibited the highest conductivity, followed by 30/50 and 70/140 mesh. This contradicted findings in shale, coal seam, and sandstone reservoirs, where multiple studies (Luo et al., 2020b; Sun et al., 2022; Wen et al., 2007; Xiang et al., 2022) have reported that larger proppant particle sizes increase fracture conductivity at the same closure pressure, as observed using the API-standard cell. The higher conductivity of 40/70 mesh compared to 30/50 mesh can be attributed to the deeper embedment caused by the lower elastic modulus of clayey-silt sediments. Marine

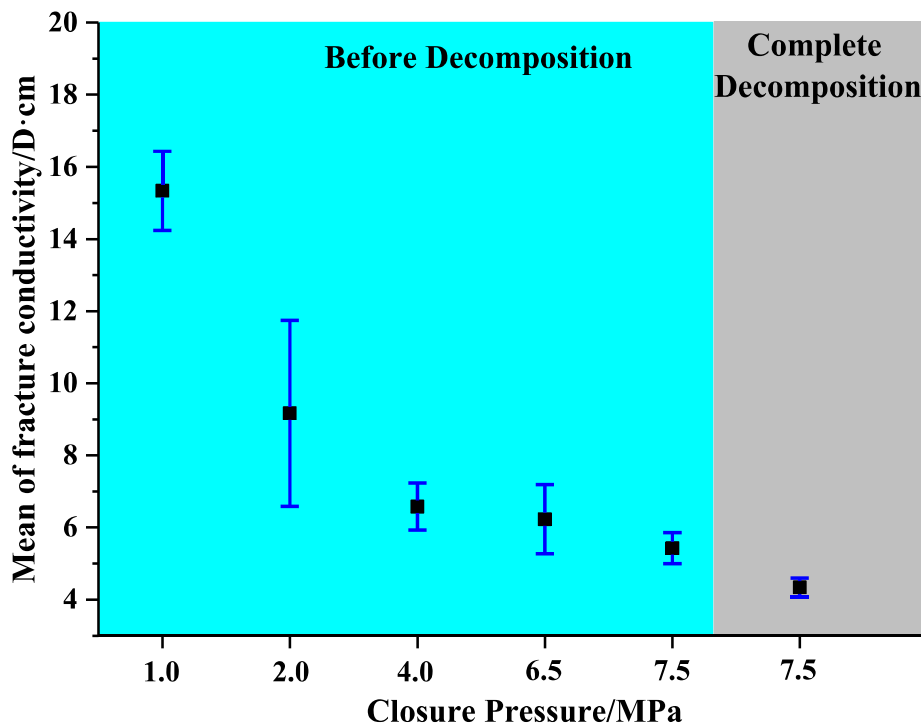


Fig. 9. Distribution of mean and standard deviation of fracture conductivity.

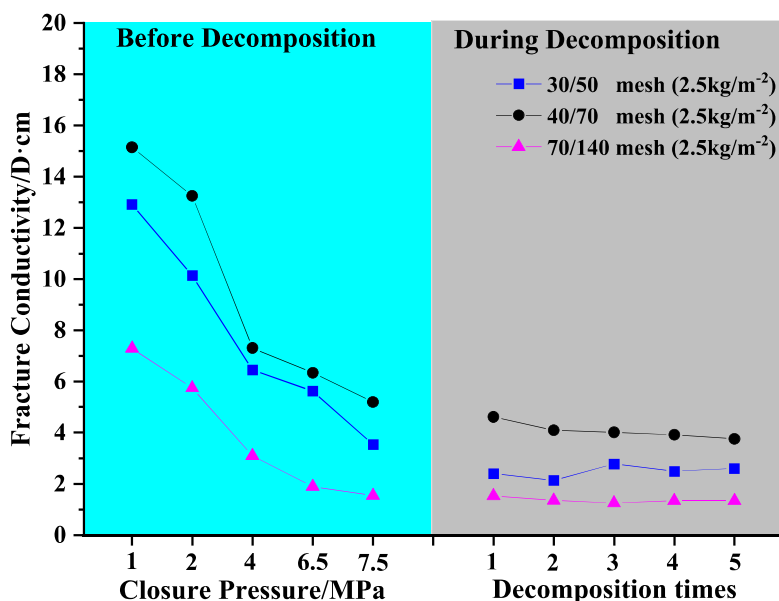


Fig. 10. Effect of different proppant mesh on fracture conductivity.

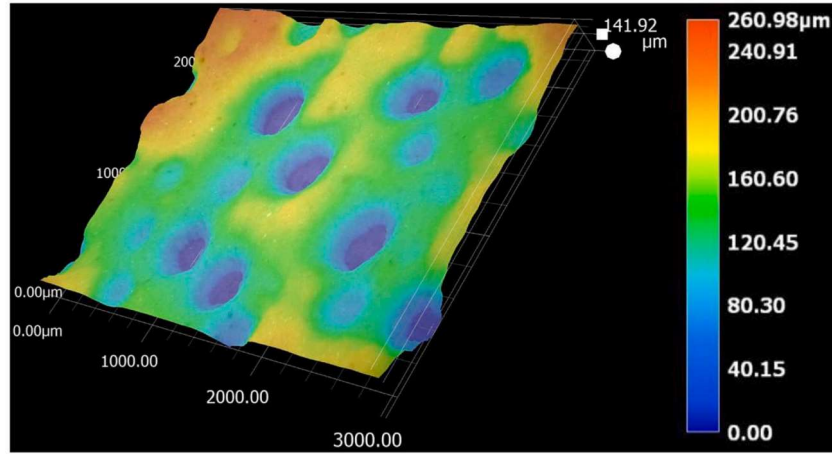
hydrate reservoirs are characterized by low elastic modulus and non-diagenetic clayey-silt sediments (Lijith et al., 2019). In this experiment, the elastic modulus of the sediments without hydrate was 300 MPa. Even with hydrates, which typically increase the elastic modulus of the hydrate-bearing sediments by 30 %–80 % (Lijith et al., 2019), the modulus remains significantly lower than that of shale reservoirs. For instance, the elastic modulus of Vaca Muerta shale and Eagle Ford shale was 24.5 GPa and 15.9 GPa, respectively (Tang et al., 2018; Zhao et al., 2022). Researchers have found that the embedment depths for 20/40 mesh proppant in Vaca Muerta shale and Eagle Ford shale were 36 μm and 68 μm , respectively, with the ratio of embedment depth to proppant diameter being <20 %. The lower elasticity of clayey-silt sediments implied that the contact surface between the proppant and the sediments was more prone to deform, leading to greater proppant embedment. This increased embedment resulted in decreased porosity in the interface zone, which represented the high-flow-rate channels developed at the interface between the proppant pack and the fracture. Compared with the body-centered-cubic structure of the proppant pack's core, the face-centered-cubic structure of the interface zone is more conducive to the flow of gas and water, exerting a greater influence on permeability (Yu et al., 2022). The decreased porosity in high-flow-rate channels led to a significant reduction in permeability, while embedment resulted in a narrower fracture width, ultimately leading to lower conductivity for 30/50 mesh compared to 40/70 mesh. These results indicate that proppant embedment had a more substantial impact on fracture conductivity in hydrate reservoirs.

Fig. 12 compares the propped fracture conductivities in hydrate-bearing clayey-silt sediments across various proppant concentrations. During the closure pressure loading stage, all six curves exhibited a downward trend, with a more pronounced slope change as proppant concentration increased, especially in the 1–2 MPa closure pressure range. In the hydrate decomposition stage, the change in conductivities showed a steady trend. This indicates that with the increase of proppant concentration, closure pressure remained the primary reason for the decline in fracture conductivity, and this decline rate was greater. The disparity in the decline rate was directly related to the number of proppant layers. It is noteworthy that in single-layer proppant configurations (0.3 kg/m^2 and 0.7 kg/m^2), the fracture width remained narrow. Consequently, the conductivity was only about 2 D·cm at a closure pressure of 1 MPa and stayed relatively stable (around 0.1 to 0.2 D·cm) up to a closure pressure of 6.5 MPa and during hydrate decomposition.

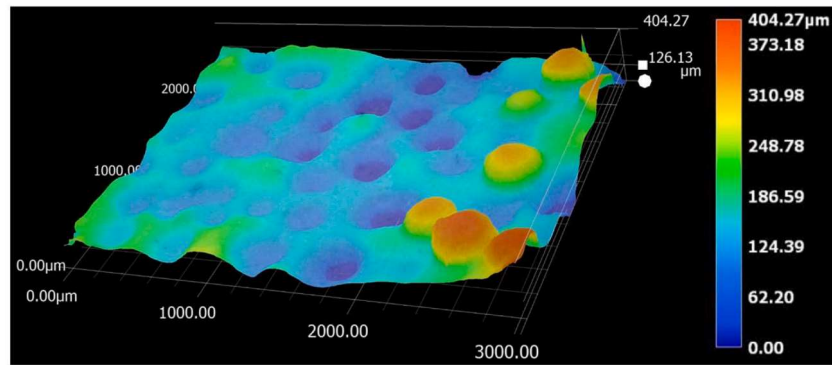
In the multilayer structure groups (1.25–7.5 kg/m^2 cases), the increased fracture width led to improved conductivity, with significant enhancements observed when the concentration exceeded 2.5 kg/m^2 . It was speculated that the reasons for this phenomenon were proppant embedment and rearrangement.

To further investigate the speculation regarding proppant embedment and its impact on fracture conductivity, White Light Optical Profilometry was employed to measure the embedment depth across different proppant concentrations at a 7.5 MPa closure pressure. In single-layer proppant configurations, the embedment depth exceeded 50 % of the fracture width (as shown in Table 2). This high embedment ratio (embedment depth/fracture width) caused the seepage channel of the proppant pack to be significantly reduced, essentially leading to blockage, resulting in a substantial decrease in permeability and the fracture conductivity approaching zero (0.1 to 0.2 D·cm). In multi-layer configurations, the embedment ratio exhibited a clear downward trend from 28.66 % to 3.96 %. Increased proppant concentration in multilayer structures led to wider fractures, which improved conductivity. However, it's noteworthy that under a 7.5 MPa closure pressure, the slope of the fracture conductivity curve with the increase of proppant concentration was significantly smaller than that of the initial fracture width with the increase of proppant concentration, as shown in Fig. 13(a). This phenomenon suggests that factors beyond proppant embedment contributed to the decline in conductivity under closure pressure. Further analysis of displacement changes, illustrated in Fig. 13(b), revealed that proppant rearrangement contributed significantly to displacement. The overall displacement change consisted of three parts: proppant pack deformation, hydrate-bearing sediment deformation, and proppant embedment depth. While part of the proppant embedment was measured by optical microscopy, part of the sediment deformation was assumed to be the same amount of deformation in each experiment due to similar saturations. Proppant pack deformation was attributed to the rearrangement of the particle structure within the proppant pack. Analysis showed that the current closure pressure was insufficient to prevent damage and elastic deformation between proppant particles, considering the closure pressure range and the proppant's elastic modulus.

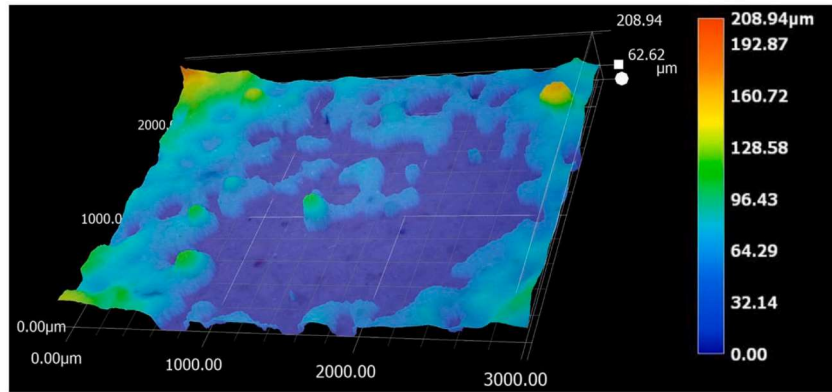
As shown in Fig. 14, proppant particles in the packing body undergone rearrangement under closure pressure, including the transformation of some cubic arrangements into rhombic ones and the filling of cavities with proppants. This rearrangement led to the increased



(a) 30/50 mesh



(b) 40/70 mesh



(c) 70/140 mesh

Fig. 11. Embedment depth of 30/50, 40/70, 70/140 mesh proppant.

number of contact points among proppants (n_0 to n_1), leading to proppant pack deformation, a loss in porosity, and a reduction in pore throat diameter (from d_0 to d_1). According to the Kozeny-Carman equation, the decrease of porosity and pore throat diameter inevitably led to the decrease of permeability. At the same time, the fracture width was also reduced by proppant rearrangement (w_0 to w_1). We conclude that greater interior compaction and proppant rearrangement were the primary mechanisms responsible for the slower growth rate of fracture conductivity compared to the rate of increase in proppant concentration.

This is consistent with the results of other unconventional reservoirs. Moreover, the combined effect of rearrangement and the low elastic modulus of hydrate reservoirs causes led to a decline in fracture conductivity by 50–80 % within the closure pressure range of 1–7.5 MPa. In shale reservoir cases, 40/70 mesh proppant concentration of 1, 3 and 5 kg/m^2 , the API fracture conductivity was only reduced by about 10–20 % in the closure pressure range of 0–10 MPa closure pressure.

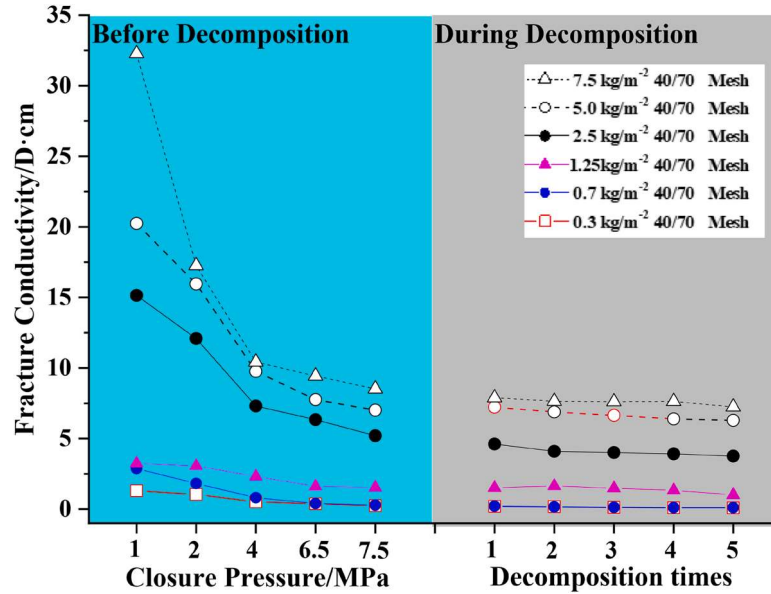


Fig. 12. Effect of different proppant concentration on fracture conductivity.

Table 2

The embedment depths of proppants at different laying concentrations.

Proppant concentration/kg·m ²	Point 1/ μm	Point 2/ μm	Point 3/ μm	Point 4/ μm	Average embedment depth/ μm	Embedment percentage of fracture width/ %
0.3	105.66	106.47	83.12	127.73	105.75	52.88
0.7	151.25	89.65	90.78	94.12	106.45	53.23
1.25	100.68	95.27	107.82	126.13	107.46	28.66
2.5	140.44	155.49	124.27	131.80	138.00	18.40
5	69.91	71.07	74.76	81.32	74.27	4.95
7.5	90.94	90.41	83.73	91.62	89.18	3.96

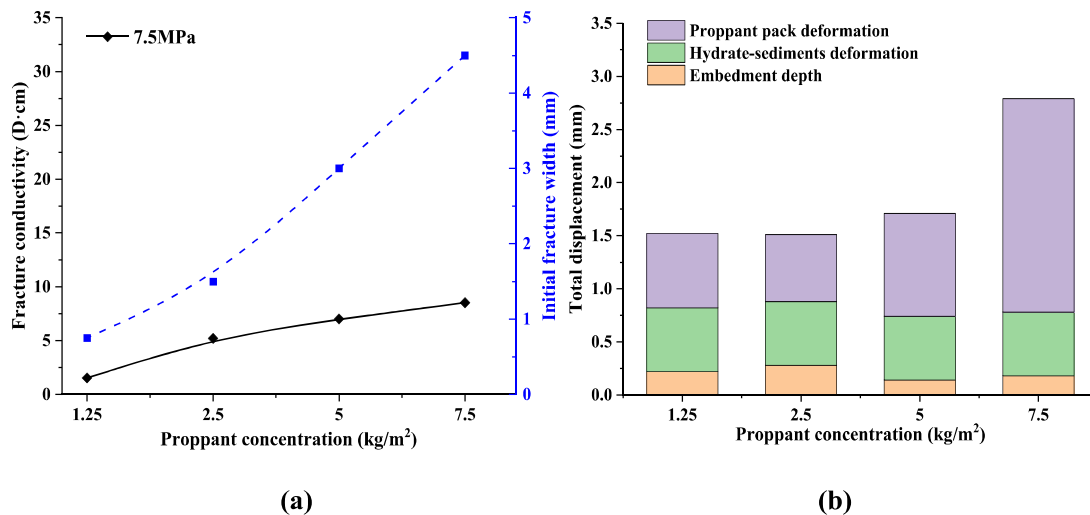


Fig. 13. Distribution of parameters changes as proppant concentration increased:(a) The curves of fracture conductivity and initial fracture width with increasing concentration;(b) The composition and change of displacement increased with proppant concentration.

3.3. The effects of fracture-contact wettability on fracture conductivity

NGH reservoirs are mostly highly water-saturated, and increased water yield can significantly enhance subsequent gas production (Guo et al., 2020; Yin et al., 2020). Understanding how water flow affects on the contact surface between fractures and proppants, and its potential influence on proppant embedment and fracture conductivity, is crucial maintaining effective fracture conductivity during offshore NGH

exploitation. Fig 15 illustrates the change of fracture conductivity during the stages of closure pressure loading, hydrate decomposition and seawater runoff (1200 mL at 10 mL/min) for Run 6. In the first two stages, similar to what was described above, the change trend of fracture conductivity and displacement showed a positive correlation downward trend. During seawater flow, the fracture conductivity, when measured using methane gas, saw a reduction of 20.68 % following the flow of seawater. Additionally, there was a displacement increase of 50 μm

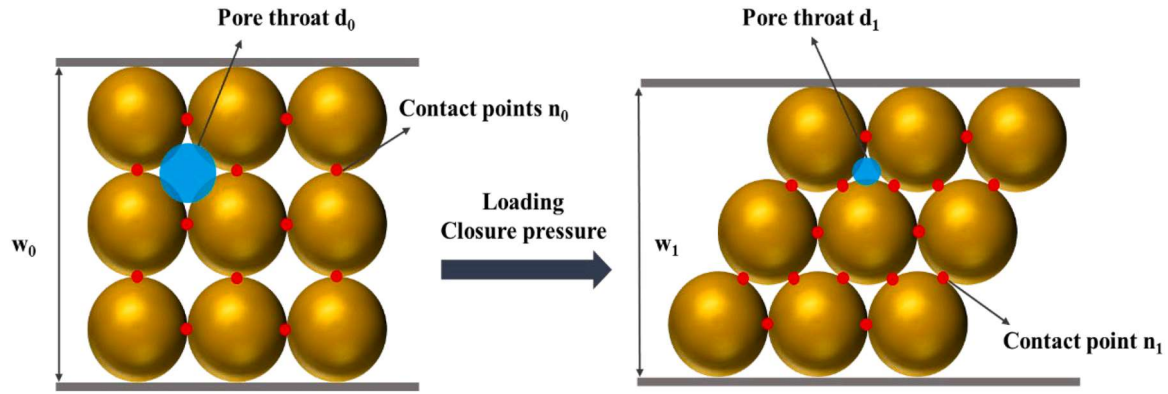


Fig. 14. The schematic diagram of proppant rearrangements.

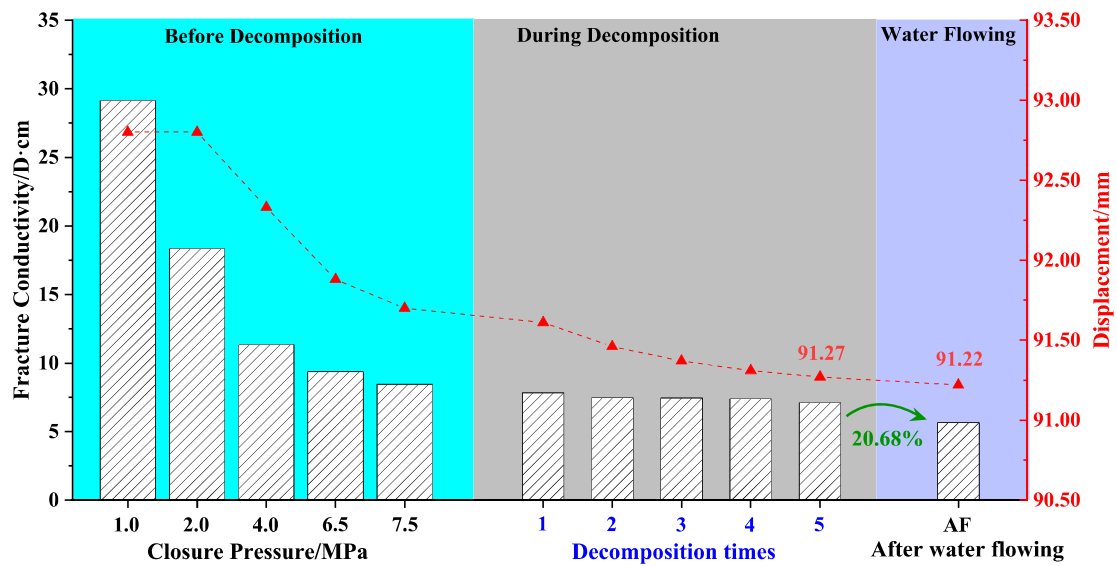


Fig. 15. Effect of different fracture contact wettability on fracture conductivity.

observed, all under a consistent closure pressure of 7.5 MPa. This change occurred because seawater runoff caused the fracture-proppant contact surface to soften, causing the clay to expand. This further embedded the proppants, resulting in a reduction in fracture conductivity. The negative impact of this water runoff fracture surface on the fracture conductivity was also observed in studies by Yu et al. (Yu et al., 2022), Guerra et al. (Guerra et al., 2018). Therefore, to maintain high fracture conductivity after marine hydrate reservoir fracturing, it is crucial to control water production during the extraction process.

4. Conclusion

This research aimed to empirically explore the fracture conductivity of propped fractures within hydrate-bearing clayey-silt sediments. It specifically focused on understanding the combined effects and interactions of closure pressure, proppant size, proppant concentration, and water flow on fracture conductivity. A detailed examination of the experimental data led to several insightful conclusions:

- (1) In hydrate-bearing clayey-silt sediments, propped fracture conductivity was primarily influenced by closure pressure. Increasing the closure pressure to 7.5 MPa, together with slow hydrate decomposition by depressurization, led to a net decrease of 11.38 D·cm. Of this reduction, 12.65% was attributable to hydrate decomposition and 87.35% to the increased closure

pressure, indicating that increasing closure pressure caused >6.9 times the fracture conductivity damage compared to hydrate decomposition.

- (2) The damage of fracture conductivity was mainly caused by proppant embedment and rearrangement of proppant pack. Displacement of fracture width increased with closure pressure, with proppant rearrangement playing a significantly larger role compared to the deformation of hydrate-sediments and proppant embedment. During hydrate decomposition, a slight increase in proppant embedment occurred as the elastic modulus decreased.
- (3) Marine hydrate reservoirs showed a more pronounced proppant embedment effect compared to other unconventional gas reservoirs, with embedment depths ranging from 20.07 % to 38.58 % at low closure pressures (0–7.5 MPa). This significant embedment depth negatively affected conductivity, preventing it from increasing alongside proppant particle size. Consequently, fractures with 40/70 mesh proppants exhibited higher conductivity than those with 30/50 mesh proppants.
- (4) Higher concentrations of proppants led to a decrease in proppant embedment as the proppant pack rearranged itself. The primary mechanisms leading to a decrease in fracture conductivity varied with the thickness of proppant loading. For fractures with a single layer of proppants, proppant embedment was the main cause of rapid conductivity degradation. In fractures with multiple layers

of proppants, conductivity reduction was primarily due to proppant compaction.

- (5) Fracture conductivity decreased by up to 20.68 % after water flowed through clayey-silty sediments under a pressure of 7.5 MPa. This decrease was due to the softening of fracture surfaces when they came into contact with seawater.

Although this study measured proppant embedment depth, some error may have occurred due to the removal of closure pressure during measurements. Future research could utilize CT scanning technology for in-situ testing of proppant embedment depth.

CRediT authorship contribution statement

Bing Li: Writing – original draft, Methodology, Investigation, Formal analysis, Conceptualization. **Yifeng Shen:** Writing – original draft, Methodology, Investigation, Formal analysis. **Youhong Sun:** Supervision, Project administration. **Yun Qi:** Methodology, Investigation, Formal analysis. **Siqi Qiang:** Methodology, Investigation, Formal analysis. **Pengfei Xie:** Methodology, Investigation, Formal analysis. **Guobiao Zhang:** Writing – review & editing, Writing – original draft, Project administration, Investigation, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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